2015 NAAQS Preliminary Transport Modeling NODA
Comment Summary
followed by excerpts of NonEGU Comments

- On January 6, 2017 EPA provided preliminary interstate ozone transport air quality information relevant to the 2015 ozone NAAQS through a Notice of Data Availability (NODA) (82 FR 1733). The comment period for the NODA closed on April 6, 2017.

- This document summarizes public comments on the NODA and does not represent any EPA view or position on the information from the commenters as captured here.

- EPA received comments on the transport modeling NODA from nearly 50 commenters
  - 21 state air agencies:
    AL, AR, CT, DE, GA, IA, KS, KY, MD, MO, NC, NV, NY, OH, OK, SC, TX, UT, VA, WI, WV, WY
  - 3 multi-state groups: *AAPCA, LADCO, and the OTC*
  - 23 industry groups:
    - *Alliant Energy (Alliant)*
    - *American Forest & Paper Association (AFPA)*
    - *American Petroleum Institute (API)*
    - *Basin Electric*
    - *Dairyland Power*
    - *Dominion Power*
    - *Duke Energy*
    - *Edison Electric*
    - *Environmental Energy Alliance of NY (EEANY)*
    - *Illinois Environmental Regulatory Group (IERG)*
    - *Kansas Utilities Group (KSUG)*
    - *Midwest Ozone Group (MOG)*
    - *Nebraska Public Power District (NYPPD)*
    - *NRG Energy (NRGE)*
    - *New York Independent System Operator (NYISO)*
    - *Oklahoma Gas & Electric (OKGE)*
    - *Southern Company*
    - *Tri-State Generation (TSG)*
    - *Tennessee Valley Authority (TVA)*
    - *Utility Air Regulatory Group (UARG)*
    - *WEST Associates (WEST)*
    - *Westar Energy*

Xcel Energy (Xcel)

- General Comment Categories
  - *A. Overarching Comments*
  - *B. Policy Comments*
  - *C. Technical Comments*
  - *D. "Out of Scope" Comments*

A. Overarching Comments

1. Some commenters said that states and industry stakeholders want clarity/reliability/stability/flexibility from EPA regarding the use of the NODA by states in SIPs. (AAPCA, Dominion, Edison Electric, MO, NC, TX, WY)

2. EPA should collaborate with states to enhance the accuracy and reliability of the modeling. (AL, CT, NC, VA, WY)

3. EPA should remodel 2015 NAAQS transport to reflect various considerations and updates provided in the NODA comments.[1]
(AAPCA, AR, Basin Electric, GA, KS, KY, MOG, NC, VA, WV)

4. EPA should move to a more recent air quality modeling platform base year.
(AAPCA[2], DE, Dominion, Duke Energy, Edison Electric, KS, OKGE, UARG, VA, Westar Energy)

5. EPA should adopt a weight-of-evidence approach for evaluating transport obligations with respect to the 2015 ozone NAAQS. (UARG, WY)

6. EPA should not approve any SIP unless all modeled emission reductions are found to be federally enforceable. (CT)

B. Policy Comments

1. Approach for Identifying Receptors

a. Receptors should be identified based on those areas designated nonattainment. (DE)

b. Sites measuring clean data based on 2016 design values should not be considered as maintenance receptors regardless of 2023 modeled design values. (TX)

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[1] There was strong support for EPA to update the transport modeling.

[2] AAPCA noted that expediency of new modeling was more important than their interest in an updated base year – i.e., that we should provide new modeling ASAP, even if that means continuing to use the 2011 platform.

c. EPA should consider international transport in determining receptors (sites that would be clean but for international transport). (MOG, TSG)

2. Contribution Threshold

(AAPCA, AL, API, AR, Basin Electric, Dominion, Edison Electric, GA, KSUG, KY, MOG, NC, OKGE, SC, TX, TSG, UARG, UT, WEST, WV, WY)

a. EPA should consider alternative threshold(s); allow states flexibility in determining thresholds in combination with other factors.

b. EPA should use the proposed 1 ppb SIL instead of a threshold of 0.70 ppb

c. EPA should use a different contribution threshold, considering
- Collective contribution
- Different thresholds for nonattainment vs maintenance
- Contributions from local vs upwind sources
- Contributions from background sources

3. NOx Reduction Potential

a. EPA should engage with industry to gather up-to-date information on the actual cost of controls for industrial boilers. (AFPA)

b. EPA should consider control measures beyond the EGU sector.
(CT, DE, Dominion, Edison Electric, KSUG, Westar Energy)

- Full installation and operation of SCR & SNCR, high demand/ozone day requirements, performance standards for EGUs; non-EGU point sources (e.g., ICI boilers, cement kilns); area sources (e.g., low sulfur fuel oils that provide NOx benefits); and mobile sources (e.g., tighter diesel engine standards, aftermarket catalysts)

c. Control measures targeted at sources operating on high ozone days should be evaluated, with consideration given to hourly/daily emission limits and performance standards. (CT)

d. NOx caps should not be developed for time periods shorter than the ozone season. (MOG)

e. Cost thresholds in CSAPR Update are far below costs used by Northeast states for establishing RACT (CT)

f. Additional national or super-regional mobile source controls are needed (MD)

C. Technical Comments - Emissions

1. EGU Emissions[3]

a. CPP is uncertain and should not be included in the base case
(AAPCA, API, AR, Basin Electric, Dominion, Duke Energy, Edison Electric, KS, MO, MOG, NC, OH, OK, OTC, TX, TSG, UARG, WV, WY)

b. NEEDs and/or IPM projections
(AAPCA, Alliant Energy, CT Dairyland Power, DE, Dominion, Duke Energy, GA, IA, IERG, KSUG, KDHE, LADCO, MD, MO, MOG, NC, NPPD, NRGE, NY, NYISO, OKGE, OH, OK, SC, Southern, TX, TSG, TVA, VA, WEST, Westar Energy, WI, WV, Xcel)

(1) Commenters provided unit-specific updates to NEEDS
(2) Commenters expressed concern that IPM shut down EGUs that are expected to continue to operate in 2023
(3) Commenters expressed concern about increases in emissions between 2011 and 2023 at certain units in the West
(4) Commenters provided unit-specific future year emissions as alternatives to IPM projections

c. ERTAC
(AAPCA, API, CT, Dominion, Duke Energy, EEANY, KDHE, MD, OK, OTC, VA, WV)

(1) EPA should use or consider using ERTAC, a combination of ERTAC and IPM, or, at a minimum compare ERTAC and IPM results, in establishing future year EGU emissions.

2. Other Emissions Categories (details in individual comment documents)

a. Non-EGU point emissions and/or effects of existing “on-the-books” controls, consent decrees, etc.
(**AFPA, CT, Edison Electric, IERG, MO, MOG**, NC, OKGE, VA, WEST, WI)

(1) Update the emissions inventory for industrial boilers and process heaters, removing units in the old Boiler MACT database and 2011 NEI that have been shut down, replaced, or converted to gas and updating facility boiler and process heater NOx emissions to reflect the new configuration.
(2) EPA’s modeling should include emissions reductions from PA RACTII, OTC Rules, MD rules, CT RACT and HEDD controls, NJ HEDD rule, Boiler MACT).

b. Onroad/nonroad mobile and/or commercial marine emissions.
(API, LADCO, NC, VA, WI)

[3] Note that a significant number of comments focused on the EGU projections.

c. Oil and gas emissions (base year and/or projections).
(IERG, TX, OK, KS, KY, WEST)

d. Biogenic emissions and lightning emissions. (WEST)

(1) MEGAN should be used instead of BEIS for calculating biogenic emissions

(2) Emissions of NO from lightning should be included in the modeling

e. Wild fire emissions. (NC)

(1) "Typical" rather than year-specific fires should be used in the modeling

C. Technical Comments - AQ Modeling

1. Modeling Domain and Resolution

a. Model grid resolution of 12 km is too coarse for properly capturing ozone in areas with complex meteorology; fine scale (4 km) modeling needed for coastal areas and/or mountainous terrain. (EEANY, MOG, NC, VA)

b. EPA should increase the vertical resolution for meteorological and air quality modeling. (TX)

c. EPA should enlarge the 12 km modeling domain to include emissions from agriculture burning in the Yucatan Peninsula and the 2016 Ft McMurray wild fire in Alberta CN. (NC)

2. Meteorology

a. Modeling should be performed for multiple meteorological years (e.g., 2011 and 2012 or 2015 and 2016). (DE, MD, MOG, NY, OTC)

b. Meteorology in 2011 was anomalously hot and not representative for Kansas, Texas and Oklahoma. (KS, OK, TX)

c. Modeling should be performed for 2014 because that year had "average" meteorology. (MOG)

3. Analytic Year

a. A base year rather than a future year should be used as the basis for assessing state contributions to interstate ozone transport. (CT, OTC)

b. EPA does not provide a rationale for using the attainment year for moderate areas as the projected analysis year. (TX)

4. Methods for Projecting Design Values and Contributions

a. For calculating RRFs, EPA should use modeled values from the grid cell containing the monitor (i.e., monitor cell) or land-only cells (for coastal sites) rather than 3x3 matrix max cell approach recommended in EPA's modeling guidance.
(AL, API, EEANY, GA, MD, MOG, NC)

b. Model performance at individual sites and days should be considered in selecting days for calculating projected design values and contributions.
(API, GA, MOG, NC, TX, UT, WEST)

c. A consistent approach (i.e., using the same set of days and validating receptor results with actual monitoring data) should be used for projecting design values and calculating contributions. (TX)

5. Approach for Contribution Modeling

a. The OSAT technique should be used for contribution modeling instead of the APCA technique that has been used by EPA for ozone contribution modeling.
(Basin Electric, MOG, WEST)

b. EPA's contribution metric should be revised to consider contributions on individual days. (DE, OTC)

c. Contribution modeling should be performed to quantify the contributions of various emissions source sectors, by state individually. (NC, KSUG, NYISO, OTC)

6. Comments on 2023 Receptors and Contributions

a. EPA's transport modeling is overly optimistic, underestimating the severity and geographic extent of the ozone problem and levels of transport impacting Connecticut and other states. (CT, UARG)

b. 2023 design values are biased low in the Northeast. (DE, OTC)

c. 2023 design values do not indicate widespread nonattainment problems. (UARG)

d. EPA should explain why some downwind monitors have higher contributions in the 2023 modeling compared to the 2017 modeling or to current measurements.
(DE, KY, Westar Energy, WV)

e. EPA should explain why KS is linked to Tarrant Co, TX when the prevailing winds in Kansas are not from north to south. (KSUG)

f. EPA has not considered the need for improvements in modeling and analysis that will be required to address the varied and complex challenges facing western states and it is inappropriate for EPA to address these modeling issues on a case-by-case basis (TSG)

7. Technical Comments on Contribution Threshold

a. A threshold of 0.70 ppb is below accuracy of monitoring data and systematic and unsystematic errors inherent in complex modeling. (API, AR, WEST)

b. The 1% threshold for the 2015 NAAQS should be 0.71 ppb, not 0.70 ppb. (MOG, UARG)

D. "Out of Scope" Comments

1. SIPs submitted in 2018 should be treated as an initial submittal with early programs; this would allow contributing states to work together to identify and implement the full solution. (MD)

2. EPA should quickly complete the 2008 NAAQS FIP. (CT)

3. EPA should propose a FIP no later than the 110 SIP deadline of Oct 28, 2018. (CT)

4. EPA has an obligation to align the dates for development of transport SIPS with the date for imposition of legally mandated controls. (MOG)

5. EPA's 2017 projected design values are flawed because they are inconsistent with current measured data. (NY, OH)

6. EPA should address controls on local emissions in nonattainment areas before seeking emissions reductions in upwind states. (AAPCA, MOG)

7. UARG urges EPA to modify its Cross-State Air Pollution Rule ("CSAPR") regulatory analytic framework, for reasons described in UARG's December 23, 2016 petition for partial administrative reconsideration of the CSAPR Update Rule. (UARG)

8. EPA should finalize its modeling guidance (Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze, December 2014). (TX)

9. EPA should develop model performance goals. (VA)

10. EPA should update the NEEDS database and then provide a comment period that focuses solely on the NEEDS database prior to the next round of IPM runs. (IA)

11. IPM is a proprietary model that often forces air agencies to guess about key inputs and assumptions. EPA should be more transparent in sharing model inputs. (AAPCA, NC)

12. It is recommended that EPA conduct an analysis of the total uncertainty associated with modeling ozone concentrations. (WEST)

Expansion of Emissions Comments

Note to self: MWCs matched to IPM sources were left out of the 2023 modeling due to an oversight. We probably want to include those in upcoming future year modeling.

American Forest and paper association:

Many of our members' facilities utilize large boilers and process heaters to produce heat or steam and sometimes electricity for their production processes. These boilers

and process heaters recently came into compliance with the Industrial Boiler MACT requirements at 40 CFR 63, Subpart DDDDD. AF&PA and AWC members' facilities also use large amounts of purchased electricity, and so their costs are indirectly affected by CAA regulations that impose costs on electric power companies (e.g., MATS and CSAPR). Therefore, we are interested in how the accuracy of EPA's analyses can be improved. Basing analysis on 2011 data is not appropriate.

An analysis of EPA's Boiler MACT database and an informal survey of AF&PA, AWC, and Council of Industrial Boiler Owner (CIBO) members showed that many industrial boilers that would have been required to install controls under Boiler MACT were either shut down or replaced with gas boilers by January 2017. A recent survey by the National Council for Air and Stream Improvement (NCASI) that covered approximately 75% of our members' boilers affected by Boiler MACT that indicates NOx emissions have been reduced by at least 5,000 tons per year at facilities located in the East and Midwest U.S due to these shut downs or conversions. These changes have led to a larger reduction in NOx emissions more than what EPA projected would occur as a result of Boiler MACT.

All of the facilities subject to the rule (other than those in North Carolina that are operating under case-by-case MACT until 2019) will have submitted a notification of compliance status to EPA by mid-2017 that indicates what boilers and process heaters are subject to the rule and how compliance is being achieved. Facilities with a Boiler MACT compliance date in January 2016 submitted their first electronic compliance report in EPA's CEDRI system in January 2017. Most facilities subject to emission limits under Boiler MACT submit an annual air emissions inventory to their state or local permit agency. In addition, the most recent ozone monitoring data shows that air quality is much improved from 2011 monitored values, suggesting that NOx emissions have indeed been reduced since 2011. Therefore, to improve the accuracy of the base case modeling analysis, EPA should use the information that has been reported to them to update the emissions inventory for industrial boilers and process heaters, removing units in the old Boiler MACT database and 2011 NEI that have been shut down, replaced, or converted to gas and updating facility boiler and process heater NOx emissions to reflect the new configuration. At a minimum, EPA should use the available information to develop the emissions inventory for the 2023 modeling, rather than speculate on what control strategies were used for Boiler MACT compliance.

In addition, following updates to the inventory and any subsequent modeling analyses, EPA should gather up to date information on the actual cost of controls for industrial boilers. EPA has recently proposed and finalized some updates to the OAQPS Control Cost Manual, but these updates have not included accurate, up to date cost information on industrial boiler emissions controls. EPA should engage with industry to gather this information and develop realistic control cost estimates and information on the scope and timing of typical industrial boiler retrofit control projects. EPA should also gather better information on the feasibility and actual effectiveness of NOx controls on industrial boilers that experience swings in operation and/or variations in fuel and fuel quality. Utilizing data collected for EGU's is not representative, as the size, design, and method of operation of many industrial boilers are significantly different than EGUs.

API

Refinery
2023 projections for refinery emissions should consider emission changes due to NSPS Subpart Ja requirements for flares, Refinery Sector Rule provisions, and new or amended refinery consent decrees. The Technical Support Document (TSD) for emissions inventory updates3 addresses 2023 emission reductions due to NSPS Ja requirements for process heaters, but does not address NSPS Ja requirements for refinery flares. The NSPS Ja flare provisions, due to the unique "modification" language (i.e., any new tie-in to the flare) resulted in a majority of flares triggering control requirements by November 2015. In some cases, new flare gas recovery installations were required. These emission unit controls should be accounted for in the 2023 projections. Additionally, the TSD does not mention any projected changes in refinery emissions due to the Refinery Sector Rule nor as a result of several new or modified Consent Decrees. Emissions impacts from these two categories should be incorporated into the 2023 projections

Nonroad
We continue to recommend that EPA compare forecasted diesel non-road fuel consumption with available real-world data on diesel fuel consumption trends, as well as review all NONROAD model forecasts and engine attrition trends to ensure that they are reasonable. As noted in our previous reviews of NONROAD, most publications have pointed to overestimates of emissions from non-road equipment when fuel consumption is used to calibrate the overall activity estimates.

1. Review and compare the forecast diesel non-road fuel consumption with the diesel fuel consumption trends by equipment type.
2. Review the input estimates for equipment population, activity in hours per year, and load factor.
3. Review all forecasts and engine attrition trends

Locomotive: There was no change to the locomotive estimates from the previous estimates using the older EPA national estimates dating to 2009.
We recommend that EPA make use of more detailed spatial allocation data available through State initiatives using detailed freight tonnage by rail link. Fleet turnover to Tier 4 locomotive engines, and rebuild rates for Tier 0, 1, and 2 existing engines should also be reconsidered in light of recent trends. The use of regionally specific growth rates accounting for differences in the freight mix should be considered to reflect tonnage trends for important cargo types (e.g. coal and oil).

Locomotive Emission Inventory Recommendations
1. Use the more detailed allocation data and rewrite the documentation to describe that approach.
2. Reconsider the implementation and fleet turnover to Tier 4 locomotive engines, and rebuild rates for Tier 0, 1, and 2 existing engines.

3. Consider regionally specific growth rates accounting for differences in the freight mix.

4. Consider different line-haul and switch growth rates based on relative fuel consumption trends available in annual Class I railroad reports to the Surface Transportation Board.

Commercial Marine Vessels: There was no change to marine vessel emissions except for the incorporation of updated estimates from California.
Our primary recommendation is to update this source category using vessel movement data now available for small vessels, as well as historic information for large vessels. In addition, a revision to the activity forecasts used for both large Category 3 ships and smaller Category 1 and 2 commercial marine should acknowledge regional variability in activity growth or decline.

Commercial marine emissions estimates have not changed from previous Platform versions, except to incorporate revised California emission estimates. California updated their emission estimates to incorporate a more complete estimate of the State emissions and standards for ocean going vessels (OGV) for the base year 2011 and forecasted emissions inventories.
While commercial marine emissions are not a significant fraction of the national inventory, this category can be important for certain coastal metropolitan areas. The forecasted emission reductions are most important for particulate matter and sulfur oxides due to the designation of an emission control area within the Exclusive Economic Zone (EEZ) that mandates low sulfur fuel and NOx controls for new ships built after January 2016. These factors lead to reduced NOx, PM, and SOx emissions in 2023 as shown in Table 4.

While it has been difficult to understand commercial marine activity and emissions, new activity data are available because all commercial ships and most small commercial vessels (including tugs, off-shore support and excursion vessels) are required to use Automatic Identification Systems (AIS). AIS records of the vessel's identity, type, position, course, speed, and destination can be used to estimate emissions. This data provides the potential for a real update to this source category's activity. Coupled with detailed estimates for many of the larger ports, AIS can provide accurate and spatially detailed estimates of emissions.
Forecasts of vessel activity have not changed from the previous version even though there is a longer history of activity from year to year to develop trends. In previous comments, we noted that trends in commercial marine activity vary from region to region, with inland waters showing a declining trend while ocean activity continues to increase.

Commercial Marine Vessel Emission Inventory Recommendations
We recommend a revision to base year emissions using AIS data that is now becoming available. In addition, a revision to the activity forecasts used for both large Category 3 ships and smaller Category 1 and 2 commercial marine should acknowledge regional variability in activity growth or decline using most recent trends.

Mobile Sources
Mobile sources include on-road and non-road vehicles and equipment. On-road vehicle emissions are typically the dominant mobile source category, and vehicle activity is well understood with efforts in measuring and monitoring traffic, employing vehicle registration data, and developing forecasts. The non-road category is less well understood, but that understanding varies by equipment type. Non-road activity has been divided between aircraft, commercial marine,

locomotive, and all other non-road sources. The other non-road sources include equipment inventories handled by the EPA NONROAD model.
In its 2023 Platform TSD, EPA reports commercial marine and locomotive emissions separate from other non-road equipment, but combines aircraft emissions with other point sources. Tables 1 and 2 show the relative contribution of mobile sources to the entire national emissions inventory by pollutant for 2023 and 2011. The mobile source fraction is forecasted to be lower despite overall emission reductions. For example, while EPA forecasts a 44% overall reduction in NOx, the on-road vehicle emissions fraction reduces from 40% to 22% of the total inventory,

Aircraft: The aircraft methodology remained unchanged in this version of the Platform. EPA continues to use the Federal Aviation Administration's (FAA) Terminal Area Forecast (TAF) System. Additionally, the forecast emissions did not include any changes to the emissions rates because proposed rules have not yet been finalized and will not significantly affect emissions as noted below in the documentation.
"*None of our aircraft emission projections account for any control programs. The EPA considered the NOx standard adopted by the International Civil Aviation Organization's (ICAO) Committee on Aviation Environmental Protection (CAEP) in February 2004, which is expected to reduce NOx by approximately 3 percent by 2020. However, this rule has not yet been adopted as an EPA (or U.S.) rule and, therefore, its effects were not included in the future-year emissions projections.*" (EPA 2016)
There are no further recommendations for this source category because the emission estimation method is appropriate.

O&G sources include upstream (i.e. well site) and midstream (i.e. compressor station and gas plant) mobile, area, and point emissions as described in the 2023 Platform TSD. The development of O&G emission inventories is an evolving area of inventory analysis and warrants close scrutiny.

In the 2011 v6.3 EPA Modeling Platform, point O&G sector sources are defined more broadly according to facility NAICS code (see Table 5) in contrast to previous versions (e.g. v6.0 Platform) in which pt_oilgas sector sources were limited to a narrow range of source categories and did not include most compressor engines operating at O&G point source facilities. All equipment at a facility with an O&G applicable NAICS code is now included in the pt_oilgas sector. Large increases in point source O&G sector emissions from the 2011 v6.0 Platform to 2011 v6.3 Platform (see Table 6) are due primarily to the revised definition of the pt_oilgas sector. Since pt_oilgas sector emissions are now defined by applicable NAICS codes, midstream sources across the O&G sector are forecast with growth rates that are consistent with the np_oilgas sector. These changes to the pt_oilgas sector definition are consistent with our previous recommendations on the v6.0 Platform O&G inventory. We note that emissions added between the base year and future year are added at base year point source locations; however, added midstream emissions are expected to be located at both existing facility and new facility locations. This will introduce some spatial and magnitude uncertainties when projections are made from 2011 to 2023

Midstream O&G Emission Forecast Methodology: EPA updated its definition of the point source oil and gas (pt_oilgas) sector by designating applicable oil and gas sources by North American Industry Classification System (NAICS) code. All types of sources at a facility with an applicable NAICS code are classified as pt_oilgas sources. Previously, midstream compressor engine O&G sources were included in the point nonipm sector rather than the pt_oilgas sector. Because the pt_oilgas sector is defined by facility NAICS, the pt_oilgas sector more accurately represents point source O&G emission sources, including midstream compressor engines. The pt_oilgas sector and nonpoint O&G (np_oilgas) sector growth factors are consistent. We continue to recommend that EPA consider using basin-level growth factors rather than aggregate growth factors over National Energy Modeling System (NEMS) regions.

EIA AEO forecasts of oil and gas production are aggregated over a small number of large geographical NEMS regions. Forecasting future year oil and gas emissions has many uncertainties as forecasts depend on economic conditions (e.g., price of natural gas), identification of new oil and gas plays, availability of exploration and development equipment and regulatory requirements. However, the usage of projections at the scale of the NEMS region is problematic because areas that are known to be subject to intensive development are forecasted to grow at the same rate as areas which are not expected to be areas of intensive development. This leads to the assumption that oil production growth in a very active basin, such as the Permian Basin, is the same as growth in a less active basin, such as the Paradox Basin.

To forecast oil and gas area source emissions, EPA has used oil production, gas production, and a weighted surrogate that combines oil and gas production. Oil and gas emissions are typically forecasted based on surrogates in addition to oil production and gas production including annual spud counts, and well counts by well type. For example, drill rig emission forecasts would be most closely associated with the change in the number of spuds drilled from the base to the future year rather than a production surrogate. In a basin where there is a high rate of production decline for existing wells, there may be a high rate of drilling to bring new wells online to compensate for declining production; in such a basin future drilling rates (and active well count) may increase while there is little or no growth in gas and/or oil production. In summary, production forecasts are expected to differ from spud counts and well counts based on drilling trends and well decline. This should be recognized by EPA and, if possible, accounted for in oil and gas growth estimates.

EIA makes detailed basin-level data available in its Drilling Productivity Report[6] for Bakken, Eagle Ford, Haynesville, Marcellus, Niobara, Permian, and Utica Shale Plays. These regions accounted for a vast majority of oil and gas production growth in the US since 2011. The EIA has more granular forecast data which, if implemented by EPA, would improve EPA air quality modeling[7]. We understand that EPA is in the process of developing frameworks for integrating more granular EIA oil and gas forecasts into future modeling platforms.
We continue to recommend that EPA consider using basin-level growth factors rather than aggregate growth factors over NEMS regions

EPA emission control assumptions reflect O&G New Source Performance Standards (NSPS) OOOO and OOOOa. Application of O&G NSPS OOOO and OOOOa controls in 2023 is limited to new emissions added above the base year emission inventory and does not account for sources that must adhere to O&G NSPS requirements as a result of facility modification. Additional flaring emissions resulting from adherence to O&G NSPS OOOO and OOOOa emission control requirements are also not accounted for in the 2023 future year inventory. We continue to recommend that EPA consider adding emissions resulting from additional flaring activity as part of compliance with the O&G NSPS OOOO and OOOOa. We also recommend that EPA more fully document the limitations of applying O&G NSPS requirements to only new emissions and not modified facilities.

There are substantial VOC emission reductions resulting from O&G NSPS OOOO and OOOOa control requirements. O&G NSPS controls are estimated to reduce a total of 2.5 million tons of VOC in 2023 from the source categories listed in Table 8. The 2011 v6.3 Platform includes reductions from fugitive components and pneumatic pumps which were not included in earlier platforms (e.g. 2011 v6.0). Fugitive component and pneumatic pump control in the 2011 v6.3 Platform is based on NSPS OOOOa regulatory requirements promulgated in 2016. However, additional flaring emissions due to O&G NSPS OOOO and OOOOa controls are not included in the modeling platform.

O&G NSPS controls for storage tanks, pneumatic controllers, compressor seals, fugitive emissions, and pneumatic pumps are applied to only new emissions that are added above 2011 emissions for the 2023 future year. Controls applied to modified sources that must adhere to O&G NSPS requirements are not explicitly included. Additionally, the effects of well decline on the magnitude of emissions available for controls are also not explicitly included. However, we know of no existing data or methodologies that would provide reliable estimates of the fraction of sources that must adhere to the O&G NSPS due to modification provisions and we understand that the 2023 future year forecast methodology does not allow for estimation of well decline. Therefore the effects from NSPS and well decline on the 2023 projected O&G inventory are highly uncertain. We recommend documenting the limitations of the application of O&G NSPS controls to the future year 2023 inventory.

State Regulations: The impact of federal regulatory programs on emissions is accounted for in the future year emission inventory and documented in the 2023 Platform TSD. State regulatory programs which target O&G emissions also have the potential to impact emission inventories. State regulatory programs should be accounted for in forecast year inventories and if they are not accounted for, this should be documented in the TSD report.

The effects of state specific rulemakings on O&G emissions are typically included in the 2011 inventory but were not taken into account in future year inventory forecasts. In the case that a state's regulations controlled base year emissions substantially, leading to future year emissions controls that were similar to the base year, the modeling platform methodology could overestimate emission control factors leading to future year emissions that are biased low. In the case that a state's regulations required more control from the base year to the future year relative to federal controls, emissions would be overestimated in the current modeling platform. Because of states' individual requirements and methods for incorporating these requirements into O&G emission inventories, including the effects of state specific rulemakings into the modeling platform is expected to be challenging

See tables in original text for supporting info

CT DEEP

- EPA should consider measures beyond the EGU sector (e.g., full installation and operation of SCR & SNCR, high demand/ozone day requirements, performance standards) to also include non-EGU point sources (e.g., ICI boilers, cement kilns), area sources (e.g., low sulfur fuel oils that provide NOx benefits) and mobile sources (e.g., tighter diesel engine standards, aftermarket catalysts).

- I didn't see anything specific on non-EGUs; they do note that SO2 from MWCs should be reduced, but those were dropped from the projection anyway…

Edison Electric

- They had insightful comments, but I didn't see any actions to take on non-EGU emissions

IERG (Illinois)

2015 VOC and PM emissions from the *ptnoipm* sector are already lower than EPA's 2023 projection. This is notable **because the 2015 emissions do not reflect reductions in emissions resulting from regulations in the CoST control packet**, largely reductions from Boiler MACT. IERG suggests that EPA review the Illinois point source actual emissions and consider trends and actual reported emissions, and provide the necessary adjustments to the *ptnoipm* sector.

As part of its assessment for the 2010 1-hour SO_2 NAAQS designation recommendations, the Illinois EPA reviewed SO_2 emissions from sources surrounding several EGUs subject to regulation under EPA's Data Requirements Rule (DRR).[10] While IERG understands SO_2 is not a precursor pollutant to ozone formation, we note that the EPA's modeling platform used in the Preliminary Interstate Ozone Transport Modeling Data for the 2015 Ozone NAAQS projected emissions of all criteria air pollutants, including SO_2. Therefore, we note the following item**s** related to EPA's SO_2 projections. This included sources in the area surrounding the Wood River Power Station in Madison County, Illinois. An Illinois refinery (EIS Facility 7940411) was included in this DRR assessment, including publicly available SO_2 emissions data for 2012 – 2014 which was relied upon for the SO_2 designation recommendation. EPA projects SO_2 emissions from this EIS Facility 7940411 to be 1,670.53 tons per year in 2023.[11] Actual reported SO_2 emissions for 2014 from the Illinois EPA DRR assessment were less than the 2023 projection, at 1,103.42 tons. Actual 2014 SO_2 emissions are 34 percent lower than EPA's projected 2023 value. Given this one example where EPA's 2023 projection appears to be in question, there may be others. EPA should consider revising its emission projections for this Illinois refinery and other SO_2 emitting sources for which more accurate SO_2 actual emissions data may be available.

A cursory review was conducted of one recently-issued, active Prevention of Significant Deterioration (PSD) permit selected from Illinois' permit database, and this permit was reviewed to determine whether the facility's emissions had been appropriately captured in EPA's 2011 and 2023 emission inventories. The selected permit was for Cronus Chemicals LLC (EIS Facility 16787211), which was issued in 2014.[12] Emissions from the proposed facility are not included in the 2011 inventory and are included in the 2017 and 2023 inventories.[11] While this is a correct approach, the facility is listed as being located in Will County, Illinois. This is not correct. The facility is permitted to be constructed in Douglas County, Illinois, approximately 140 miles south of Will County. The location of this facility should be corrected to assure accurate modeling of 2023 emissions from Illinois

As the refining industry is one of the larger, non-EGU industries in Illinois, IERG has reviewed EPA's projected 2023 emissions from the refining industry and has come to the conclusion that in spite of lower forecasted production and emissions in EPA's 2023 projections, EPA has underestimated emissions reductions that will occur from the industry between 2011 and 2023.[13] Specifically, NOx, SO_2, and VOC emissions will be reduced below 2023 projections. This is a result of reductions from the implementation of numerous Federal regulations that were not included in EPA's CoST control packet.[14] Below is a list of regulations that will result in emissions reductions from the refining industry in Illinois:

1. NSPS Subpart JA Flare Requirements – Effective November 11, 2015
   https://www.regulations.gov/document?D=EPA-HQ-OAR-2007-0011-0320. Per this regulation, EPA has estimated that the flare requirements in NSPS Subpart JA will impact 400 existing flares and will result in 3,200 tons/yr of SO_2, 1,100 tons/yr of NOx, and 3,400 tons/yr of VOC reductions nationwide.
2. Refinery Sector Rule (NESHAP, Subparts CC and UUU (Effective 2019)
   https://www.epa.gov/sites/production/files/2016-06/documents/2010-0682_factsheet_overview.pdf

Three Consent Decrees have been issued for facilities in Illinois, but have not been accounted for in projected emissions reductions:

1. Illinois Refinery – Issued 2005 with several amendments
   https://www.epa.gov/enforcement/conocophillips-global-refinery-settlement
   https://www.epa.gov/enforcement/citgo-petroleum-corporation-and-pdv-midwest-refining-llc-settlement#injunctive.
   https://www.epa.gov/enforcement/first-amendment-2012-us-v-marathon-petroleum-co-clean-air-act-consent-decree

   IERG requests that EPA account for emissions reductions from these various refinery-related control and consent decree items in the 2023 emissions projection

35 IAC Part 217 Subparts E, F, G, H, I, and M contain NOx emission limits for various source categories including Industrial Boilers, Process Heaters, Glass Melting Furnaces, and Cement and Lime Kilns, among others. Changes and additions to Part 217 were adopted in Illinois to reduce NOx emissions in order to comply with previous ozone NAAQS standards.[22] Illinois EPA estimated NOx reductions of 20,666 tons/yr (from 2005 base year), with approximately 14,800 tons in reductions from EGU boilers.[23] An evaluation of the CoST control packets detailed in Technical Support Document (TSD) Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023 indicate that NOx reductions resulting from the promulgation of this rule were not accounted for in EPA's emissions projections.

IERG also notes that Section 4.2.4.7 of the CoST control packets detailed in Technical Support Document (TSD) Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023 indicates that EPA believes that NOx reductions at refineries and chemical plants resulting from RACT regulations occurred prior to 2011. This is not an accurate assumption, as compliance dates for emission reduction requirements in 35 IAC 217 occurred, for the most part, in 2015.

While the most recent amendments to Part 217 may not yet be a part of the State Implementation Plan (SIP) approved by EPA, it is an Illinois final rule and the NOx reductions resulting from this rule should not be disregarded in EPA's analyses. IERG requests that NOx reductions resulting from 35 IAC 217 Subparts E, F, G, H, I, and M be incorporated into EPA's CoST control packet for applicable Illinois sources.

35 IAC Part 214 contains SO_2 emission limits for various source categories including New Fuel Combustion Emission Source, Existing Solid Fuel Combustion Emission Sources, and Petroleum Refining, Petrochemical and Chemical Manufacturing, among others. Recent amendments to Part 214 were adopted in Illinois EPA to reduce SO_2 emissions per the 2010 1-hour SO_2 NAAQS.

35 IAC Part 214 Subparts B and D impose new limitations on the sulfur content of liquid and solid fuels burned for fuel combustion stationary sources across the state. TSD Updates to Emissions Inventories for the Version 6.3, 2011 Emissions Modeling Platform for the Year 2023, Section 4.2.4.5, Pages 68 and 69, list state fuel sulfur rules that were taken into account as part of the CoST control packet.[24] This list does not include the fuel sulfur rules from 35 IAC 214 Subparts B and D. IERG believes Illinois' new fuel sulfur regulations should be accurately reflected and included in EPA's CoST control packet projections used to project 2023 emissions.

Additionally, 35 IAC 214 Subpart AA includes SO_2 emissions limits for specific sources. An example review of one listed source, EIS Facility 4504711 reveals that the 2023 projected emissions do not account for source specific emission limits as required per 35 IAC 214, Subpart AA. The 2023 projections estimate that there will be 7,003 tons of SO_2 per year emitted from this facility's calciners.[26] Section 214.603(h) limits SO_2 emissions from this facility's calciners to a combined 187 lb/hr or a total of 819.06 tons per year. This is a significant decrease from the 2023 projected emissions. In order to accurately reflect SO_2 emissions reductions, IERG requests that reductions associated with 35 IAC 214 Subpart AA be added to the CoST control packet as this is a final Illinois rule that is currently in effect.

35 IAC Parts 218 and 219 includes VOC emission limits for various source categories located in the Chicago and Metro-East areas. Sections 218.187 and 219.187 are applicable to a wide range of industries for Other Industrial Solvent Cleaning Operations and have a compliance date of January 1, 2012. These sections impose VOC emissions restrictions on specified solvent cleaning activities at facilities that emit more than 500 lbs per calendar month of VOC in the absence of air pollution control equipment. IERG requests that reductions associated with Sections 218.187 and 219.187 be added to the CoST control packet as this is a final Illinois rule that is currently in effect.

A review of NOx emissions associated with the *nonpt* sector in Illinois reveals that approximately 50 percent of the NOx emissions from this sector are from residential natural gas combustion.[27] EPA has projected that there will be no change in the NOx emissions from residential natural gas combustion between 2011 and 2023. IERG asserts that it is not appropriate to assume no change in NOx emissions from this source category.

1. Between 2011 and 2023, older, less efficient residential furnaces and hot water heaters will be replaced with significantly more energy efficient versions. For example, older natural draft furnaces (20-40 years old) are typically 65-75 percent efficient, and forced vent furnaces through a metal flue pipe (75-80 percent efficient), will systematically be replaced with state of the art units at 90 percent or more efficiency.
2. EPA has a proposed rule that would reduce NOx emissions from this sources category, Energy Conservation Program: Energy Conservation Standards for Residential Furnaces [28] https://www.federalregister.gov/documents/2016/09/23/2016-22080/energy-conservation-program-energy-conservation-standards-for-residential-furnaces. [29] EPA-HQ-OAR-2016-0751-0009, Section Section 4.2.3.5 Oil and gas industrial source growth (nonpt, np_oilgas, ptnonipm, pt_oilgas) Table 4-13.

Comment on Consumer and Commercial Household and Personal Care Products – nonpt

A sizable proportion of the VOC emissions in the *nonpt* sector result from the use of residential and commercial solvents. EPA has projected that there will be no change in the VOC emissions from this source category between 2011 and 2023. IERG believes that this is not a sound assumption, as consumer products are trending towards reduced VOC content in their formulations due to market driven forces demanding "greener" products. IERG requests that EPA reconsider the decision to hold constant VOC emissions from this source category from the 2011 to the 2023 annual emission inventory

Use of 2023 Projection Factors Derived from AEO2016 for each EIA Supply Region – np_oilgas, pt_oilgas

Illinois is designated as part of the East Oil and Gas NEMS Region by the U.S. Energy Information Administration.[29] EPA projects emissions from natural gas using factors derived from AEO2016 for each EIA supply region. The East supply region has the highest average oil and gas projection factor listed in Table 4-13 of the document (4.777 for natural Gas Dry Production). IERG believes that this growth factor is likely associated with the Marcellus and Utica natural gas fields which are not located in or near Illinois. Although the U.S. Department of Energy includes Illinois in this region, data published by the Illinois EPA[30] does not support recent increases in production and/or associated emissions in this sector in Illinois. IERG requests that EPA make the necessary corrections to the inventory to update improve its inventory.

Upon review of the *np-oilgas* sector inventory for Illinois, IERG identified a reasonably large increase in projected NOx emissions for SCC 2310000330, described as *Industrial Processes; Oil and Gas Exploration and Production; All Processes; Artificial Lift*. It would appear that the projection factor used to project 2023 NOx emissions is 1.901, the same factor identified for the 2023 projection factor for oil production in the EIA East supply region.[3] IERG is unsure if the LADCO data referenced[32] would change this SCC projection factor or not, and, as a broader comment, it is unclear if EPA used any of the LADCO projection data as there are no references to the LADCO data in Table 4-12.[33] [30] http://www.epa.illinois.gov/topics/air-quality/air-quality-reports/2015/index. In particular, tables included at Appendix C, Point Source Emission Inventory Summary, show small increases in emissions for "Oil and Gas Production" category. [31] EPA-HQ-OAR-2016-0751-0009, section 4.2.3.5 references three broad sources of projection information for industrial sources, including oil and gas. One such source was identified as LADCO. [32] EPA-HQ-OAR-2016-0751-0009, pg 48-49. [33] EPA-HQ-OAR-2016-0751-0009, Table 4-12, titled Sources of new industrial source growth factor data for year 2023 in the 2011v6.3 platform.

Use of Factors Provided by LADCO – nonpt, np_oilgas, ptnonipm, pt_oilgas

The Technical Support Document, Preparation of Emission Inventories for the Version 6.3, 2011 Emissions Modeling Platform indicates that LADCO provided usable projections and controls data for various states, including Illinois.[34] EPA chose not to use the growth data for oil and gas-specific processes (SCC-level), but rather used their own approach because it was more "comprehensive and consistent nationally". It also appears that EPA did not use *nonpt* factors provided by LADCO except for a limited number of applications (agricultural tilling, pesticide application, degreasing operations, and residential wood combustion).

As discussed in previous comments regarding 2023 projections for the oil and gas sector, EPA appears to over-estimate the increase in oil and gas production in Illinois because EPA uses a projection factor that is reflective of oil and gas production growth associated with the Marcellus and Utica natural gas fields that are not located in Illinois or in the vicinity

IERG recommends that EPA consider state and regional information provided by LADCO to more accurately forecast emissions from Illinois.

LADCO

Onroad

Why is diesel idling such a dominant contributor to the 2023 inventories? LADCO's review of the emissions estimates provided by EPA shows that the diesel idling components of the 2023 inventory contribute significant quantities of NOX emissions to the inventory. Chart 1 Shows the relative contribution from diesel idling

Why is there significant increases in light duty diesel vehicle populations and vehicle miles traveled given the recent Volkswagen legal actions? Is EPA planning on updating the future year fleet mix and travel to be more reflective of this reality?

There is a 40+ fold increase in E85 from 2011 to 2023. Does this make sense? Why do the 2017 numbers have nearly a 600 times increase from 2011(?) in E85? LADCO is recommending to our states that they update the 2023 VMT estimates in the form of SMOKE VMT files. The states are working to update this info with their MPO's but given schedules for updated modeling runs necessary for the travel demand models, this information will not be available to EPA before the end of the comment period. We hope EPA will be receptive to this data at that time

Nonroad

After review of the emissions estimates and the related increase in emissions from all sectors of the inventory LADCO has identified specific sectors that need further review. See Chart 2 for sector breakdown. The first of these is recreational equipment where review of the MOVES non-road input file NATION.GRW revealed a national growth rate for growth indicator #95 much higher than expected for recreational equipment. See Chart 3. After review with the states we believe this number should be more reflective of a flat growth between 2011 and 2023.

LADCO states reviewed the equipment populations used in NONROAD for 2011 to 2023 and compared those to historic registration databases at the states for these equipment types. We believe the local data is clear that the current growth rates and derived populations are incorrect. Snowmobile populations are compared in Chart 3B. We can see that the model is overestimating between 2 and 5 times too many snowmobiles in the LADCO region. We found similar problems in all terrain vehicles and offroad motorcycles where the models predicted two to three times as many vehicles as registrations would indicate. We believe that the growth rate in Chart 3 for the pre-2011 equipment populations is resulting in 2011 population that are too high. Second, we accept the growth curve that flatten out post 5

2011. Our data shows that overall registrations are relatively flat between 2000 and 2015 in most states. The growth rates should show uniform positive year over year growth in the 1-2% per year range. Regarding nonroad emissions for recreational equipment, as well as pleasure craft, large increases in NOx from 2011 to 2023 are found for the 2-stroke gasoline categories in these subsectors. In contrast, VOC emissions for these categories significantly decrease from 2011 to 2023. Chart 4 shows nationwide NOx emissions for these categories from the EPA's 2011 Modeling Platform, version el, and Chart 5 shows these same emissions from a default MOVES run, using the national scale, provided by the state of Wisconsin. Similarly, Chart 6 shows nationwide VOC emissions for these categories from the EPA's version el and Chart 7 shows these same emissions from Wisconsin's default MOVES run. Finally, Chart 8 shows the nationwide vehicle populations from Wisconsin's default MOVES run.

These charts show similar emission levels and changes over time between the Modeling Platform runs and the default MOVES runs. (One reason for the modest differences is that the default MOVES runs were done at the national scale instead of the more precise county scale.) This similarity suggests that the changes in emissions from 2011 to 2023 largely come from the NOx emission rates in the MOVES model. Since the NOx emissions increase more than the vehicle populations increase, compare Chart 5 with Chart 8[1], the NOx emission rate in MOVES look to be higher in 2023 than in 2011. We suggest that EPA examines the NOx emission rate trends in the MOVES model for 2-stroke gasoline recreation equipment and 2-stroke gasoline pleasure craft and adjust the emissions in the Modeling Platform if the trends are not realistic.

Kansas City Board of Public Utilities

Some stack parameters need adjusting

KS DH&E

Incorporate recent reductions to EGU emissions and new wind generation.
Consider ERTAC EGU
Replace 2011 platform with newer platform
Prefer 2014NEI-based platform
No concrete actions aside from redoing with new platform.

KY

Improvements to non-EGU control data are important.
Excessive growth in the oil and gas emissions when decrease is expected (hold constant?)

MO DNR

The ptnonipm CoST Projection Packet for Missouri has facility or unit closure for years 2011 to 2014. The air program is attaching an Excel file (2015_P70_ptnonipm_closure.xlsx) with additional facility/unit closure data for 2015. In addition, Veolia Kansas City Energy Inc. (EIS ID 7663611) was issued a construction permit that requires three of its boilers (1A, 6 and 8) to combust natural gas exclusively. Table 5 lists potential emissions from these three boilers for several pollutants as replacements to the 2023 NODA emissions. Boiler 7 (ID 12449813) still combusts natural gas and fuel oil; therefore, 2023 NODA emissions were not replaced. These fuel switches are required in the facility's Title V Permit Renewal, due in 2018. The air program is requesting EPA update the 2023 emissions for Veolia. *Table 5: Veolia Kansas City Energy Updated 2023 Emissions*

MOG

We left out PA RACT. RACT II threshold is 100 and 50 TPY for NOx and VOC respectiveloy in the 5 county Phila area

We left out OTC model rules – state of MD provided a list of incremental NOx and VOC emis reduction programs to be implemented prior to 2017, resulting in 27000 tons NOx and VOC reductions exceeding 22000 tons (see table in comment) – many are related to mobile sources, a few are stationary.

CT RACT and HEDD – CT DEEP committed to evaluate additional NOx reductions for sources regulated under RCSA section 22a-174-22 and MWCs regulated by RCSA section 22a-174-38 and must be effective by Jan 1, 2017 Also they discuss HEDD controls being needed.

Boiler MACT: At least 5000 tons of NOx reductions may not have been accounted for by EPA in its modeling

NC

Point Source Sector - Non-EGUs: The DAQ identified errors in the facility closure, growth factor, and boiler maximum achievable control technology (MACT) control files for the non-EGU point source sector. The DAQ is submitting replacement files that correct the errors. The errors in the facility closure file appear to be caused by EPA augmentation of the facility closure file that the DAQ submitted through Mid-Atlantic Regional Air Management Association (MARAMA) for the 2017 transport modeling platform. *NCDAQ_CLOSURES_2011v6_2_040617.xlsx NCDAQ_PROJECTION_PtGFs_2011_2023_040517.xlsx NCDAQ_CONTROL_2011v6_2_2023_Boiler_MACT_040617.xlsx*

The DAQ identified errors in some of the point source records for North Carolina provided in the spreadsheet named "BETA_Projections_PT_NonERTAC_20" in EPA's growth factor file "ptnonipm.xlsx." The DAQ requests that EPA replace all North Carolina records in this file with records from the file "*NCDAQ_PROJECTION_PtGFs_2011_2023_040517.xlsx*" submitted to the docket with these comments

In addition, the DAQ is planning to develop a set of new non-EGU point (and nonpoint) source growth factors later this year to support 2023 air quality transport modeling being performed by MARAMA. These growth factors, which will be available for all post-2011 years through 2030, will reflect the most current available information as of the time of their development (e.g., forecast data from the 2017 version of the EIA's AEO). The DAQ will supply these growth factors to EPA (either directly or via MARAMA) for use in future EPA modeling platform development when they are available.

The DAQ revised the control efficiency data for Evergreen Packaging (formerly Blue Ridge Paper Products), Canton Mill (FIPS 37087; plantid 7920511) for two emission units (pointid 3184213 and 3184713) and added records for two addition emission units (pointid 3185313 and 3185913) to reflect recent data obtained from a permit revision for the plant. The DAQ submitted to the docket with these comments the entire boiler MACT control file (*NCDAQ_CONTROL_2011v6_2_2023_Boiler_MACT_040617.xlsx*) that incorporates these revisions for this plant

Nonpoint (Area) Sector: For wildfires, the DAQ requests that EPA remove the Pains Bay and Juniper Road wildfires from the 2023 projection year inventories because these fires were atypical events that occurred in 2011 and are not representative of a typical fire year for North Carolina. The acreage burned by the Pains Bay wildfire was approximately 21,290 acres and 31, 140 acres for the Juniper Road wildfire. The average acreage burned for the remaining wildfires in the 2011 NEI v l is on the order of 1,000 acres burned. The DAQ strongly suggests that any 2011 modeling done to represent a "typical" base year, as is usually the case in policy relevant modeling runs that are compared to future year (e.g., 2023) modeling runs, that these specific wildfires be excluded and "typical" wildfire emissions be used instead. *Note the DAQ made this same request in its previous comments on the 2011 NE!vl and the NODAs for the initial 2018 and revised 2017 emissions modeling platforms; however, EPA has ignoredthis request.*

With respect to nonpoint source growth factors for North Carolina, the DAQ reviewed and did not find any issues requiring revisions to EPA's growth factors reported in the following files: "afdust.xlsx," "ag.xlsx," "cmv.xlsx," and "nonpt.xlsx." The EPA did not incorporate a growth factor of "1" for the Agricultural Field Burning SCC (2801500000) in the "PROJECTION_2011v6_2_2025_nonpoi" worksheet in the "nonpt.xlsx" file although the DAQ supplied this growth factor to MARAMA for submittal to EPA. The DAQ is not sure why this record was excluded when there are entries of "1" in this worksheet for two other states (FIPS 11 and 24). However, it is the DAQ's understanding that EPA reflected a no growth assumption for this SCC for all states, based on the following statement on page 29 of the December 2016 TSD: "Fires sectors (ptfire, agfire): No growth or control – 2011 estimates are used directly

On-road Mobile Source Sector: The DAQ is submitting state-certified county-level human population projections to replace the population data that EPA used to project 2017 vehicle miles traveled by light duty vehicles (LD VMT) to 2023 values. The state-certified data will improve the accuracy of the 2023 forecast by accounting for more localized population growth. A review of the population data used by EPA, as compared to the state-certified data, showed that EPA data leads to overestimation of LD VMT for 80 counties by up to 3.8%, and underestimation of LD VMT for 20 counties by as much as 2.9%. The average overestimation is 1.7%, while the average underestimation is 0.9%. *NCDAQ_NC_Population_Projections_040517.xlsx*

Nonroad Source Sector: The DAQ requests that EPA replace default national nonroad diesel equipment population growth rates over the 1996-2015 period for the Construction and Farm sectors in the model, which reflect national growth experienced during the 1990s, with actual North Carolina historical diesel fuel consumption data for each sector as reported in official government statistics by the Energy Information Administration. The DAQ also requests that EPA use DAQ-developed locomotive projection factors that (I) more accurately reflect the effect of EPA's locomotive emission standards relative to EPA's 2011 locomotive emission estimates, and (2) incorporate North Carolina-specific projected passenger rail emissions activity growth.
NATION.GRW.txt NCDAQ_nrgrowthindex.xlsx

In addition, the DAQ's review of the growth factors in the worksheet "NCDAQ_PROJECTION_Locomotives_20" of the file "rail.xlsx" indicates that EPA did not incorporate
the DAQ's growth factors for locomotive source categories that were included in the nonpoint source growth factor file that the DAQ supplied to MARAMA who then supplied the file to EPA. These growth factors were provided for the following SCCs:
- 28500201 - Yard Locomotives;
- 2285002006 - Line Haul Locomotives: Class I Operations;
- 2285002007 - Line Haul Locomotives: Class II / III Operations; and
- 2285002008 - Line Haul Locomotives: Passenger Trains (Amtrak).

Instead of using the DAQ's 2023 factors, it appears that EPA developed 2023 factors for North Carolina by interpolating between the 2017 and 2025 growth factors that the DAQ supplied to EPA in October 2015 in response to EPA's 2008 ozone NAAQS transport modeling NODA. The DAQ requests that EPA use the year 2023 growth factor records for locomotives that MARAMA submitted to EPA in our nonpoint source growth factor file.

OK DEQ

Some EGU retirements; plus new solar and wind capacity coming online.
Said Thank you.
ERTAC pros & cons.
Move away from 2011.
CPP problems.
Prefer 2014 (2016) inventory – worked on oil and gas for this:
5 "Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5, and Regional Haze," p. 4. In addition, see the discussion on p. 16 of the same document.
2011, statewide Oklahoma NOx emissions totaled 411,509 tons. The 2014 total NOx emissions were 4.9% lower. In 2011, ozone-season EGU NOx emissions totaled 38,285 tons, a Page 7 of 9

total which excluded some units not then subject to CAMD reporting requirements. In 2016, ozone-season EGU emissions dropped to 12,761 tons, a 66.7% decrease compared to the 2011 ozone-season emissions. As EGU emissions have decreased, other NOx sources have become relatively more important. In Oklahoma, the second largest source category (after on-road mobile sources) is the combined oil and gas exploration, production, and midstream sectors. Considering the importance of that broad source category, the 2014 NEI represents a significant improvement for two primary reasons: (1) the Oklahoma NEI submission incorporated detailed inventories from over 4,000 permitted wellhead facilities in the state and (2) the National Oil and Gas Emissions Inventory Tool included basin-specific data obtained from the Greenhouse Gas Reporting Program ("GHGRP").

A brief review of the submission history for the combined oil and gas exploration, production, and midstream sector source category should help demonstrate the nature of the improvements made in the 2014 NEI submission. Very few states reported area source oil and gas emissions to the triennial NEI prior to 2008. For the 2008 NEI, Oklahoma joined a handful of states[6] who reported area source oil and gas emissions. The Oklahoma submission was based on a Central Regional Air Planning Association study prepared by Environ.[7] For the 2011 NEI, Central States Air Resource Agencies commissioned a more detailed study,[8] the results of which were incorporated into the EPA 2011 Nonpoint Oil and Gas Emission Estimation Tool.[9] The 2011 NEI represented a significant improvement over the 2008 NEI, with superior basin factors and emissions estimated for a much larger number of states. Even more improvements were made to the EPA 2014 Nonpoint Oil and Gas Emission Estimation Tool, including the incorporation of basin factors obtained from the GHGRP for the following sources: associated gas venting, condensate tanks, crude oil tanks, heaters, and pneumatic devices. In addition to using this improved version of the Tool for its 2014 NEI submission, ODEQ incorporated county-specific natural gas compositions, emission factors for pneumatic controllers obtained from a study performed by the Oklahoma Independent Petroleum Association,[10] and a detailed point-to- nonpoint crosswalk to integrate ODEQ's emissions inventory data collected from the approximately 4,500 wellhead facilities that had obtained air quality permits from ODEQ by the end of 2014.[11]
As emissions from the EGU sector have decreased, developing more accurate estimates of the emissions from the oil and gas sector has become even more important.[12] The 2014 NEI represents

the best available characterization of emissions from that sector nationwide, but especially from Oklahoma.

In ODEQ's comments submitted in response to the transport NODA for the 2008 ozone NAAQS, we discussed some of the issues associated with the potential underreporting of emissions from oil and gas facilities that fall into a "midstream gap." For the natural gas sector, the term "midstream" typically refers to all operations downstream of the wellhead and upstream of the city gate. In Oklahoma, every permitted midstream facility (including true minor and synthetic minor facilities) is inventoried as a point source and ODEQ submits all of their emissions to the triennial NEI. Many other states have procedures in place to capture emissions from this sector; however, there is little uniformity and some states have no mechanism in place to accurately estimate emissions from these sources.

While some work has been done to investigate this issue,[13] ODEQ believes that the concerns raised in our previous submission remain relevant. To address those concerns, ODEQ would like to see additional work done to explore the likelihood that a number of sources downstream of the wellhead, but upstream of the city gate may be omitted from the NEI. These facilities may fall into an inventory gap, because their emissions are below the Air Emissions Reporting Requirements Type A & B thresholds and (with the exception of the initial lateral/gathering compressor engines) there is no current mechanism for aggregating their emissions into the nonpoint oil and gas emissions estimation tool. Alternatively, it is possible that the inclusion of the lateral/gathering compressor engines in the tool has resulted in some double-counting of emissions in states like Oklahoma, where there is an effort to inventory each midstream facility as a point source.

The National Oil and Gas Emissions Committee is engaged in an ongoing effort to investigate these concerns and to propose solutions. If sufficient resources are available, we may be able to resolve these issues (e.g., by developing a third "midstream" component of the tool with a simple mechanism for point source subtraction), yielding even greater improvements in sector-wide emissions for the 2017 NEI.

ODEQ is appreciative of EPA's willingness to work with states to develop regulations in the spirit of cooperative federalism. ODEQ recognizes that the process is challenging under the best of circumstances, and especially so when state partners request substantive changes. ODEQ recognizes that the request to abandon the 2011 base year in favor of something more recent could push back the rulemaking calendar for CSAPR 3. This would definitely be the case if, as we have requested, EPA issues a new NODA for an updated modeling platform, which incorporates the 2014 NEI. While this might appear to delay improvements in air quality, ODEQ believes that a too-hasty rulemaking process could actually lead to greater delays in implementation and deferred realization of air quality improvements. Oklahoma EGUs were not subject to the CSAPR ozone-season NOx trading program until 2015. That rule was promulgated to address interstate transport associated with the 1997 ozone NAAQS. The changes to the allowances under the CSAPR update (associated with the 2008 ozone NAAQS) are due to take place this year (2017). For CSAPR 3, it is worth taking some additional time to promulgate a rule supported by more representative meteorological data and more complete emission inventory data. Ultimately, a better, more well-founded rule should yield actual emissions reductions sooner than a flawed rule that is open to challenge. Again, ODEQ appreciates EPA's consideration of our comments

OKGE

I didn't find anything new. They submitted a cover letter and resubmitted their 2016 comments, which were previously incorporated.

Sunflower

Some stack parameter corrections

TCEQ

See original doc – can't copy from it.

B.1 TCEQ updated its oil and gas info to 2015 levels and will provide it (check docket for this – otherwise contact them).

B.2 Some 2011 EGU data doesn't look correct – update?

VA:

Onroad Emissions

Many of the charts in this section are part of a detailed presentation entitled, "Review of Mobile Source Inventory in EPA Notice of Data Availability (NODA) for 2015 Ozone NAAQS." DEQ presented this information during the Maryland Department of the Environment (MDE) photochemical modeling call on March 23, 2017. Attachment 1 provides the entire presentation.

The Virginia onroad emissions are summarized by pollutant and vehicle type in Figure 3 and Figure 4. Total onroad emissions for the Commonwealth are projected to have a declining trend in the future. However, PM2.5 emissions for light-duty trucks (passenger trucks and light commercial trucks) are estimated to increase in future years. In Figure 4, onroad emissions are summarized on a percentage basis. For NOX, the percentage of emissions attributed to light-duty trucks as well as combination long-haul trucks increases in future years. The increasing percentage of NOX in future years from combination long-haul trucks is also observed nationally (Figure 5). Virginia onroad emissions are summarized by pollutant and road type in Figure 6 and Figure 7. For all three analysis years, the majority of VOC emissions occur while the vehicle is parked (off-network). These emissions include start, evaporation, and idling processes. In Figure 7, these emissions are summarized on a percentage basis. For NOX, in Virginia, only about 30% of emissions occur on urban roads in each analysis year. For VOC, over 70% of all onroad emissions occur off-network. This large percentage of offnetwork VOC in future years is also observed nationally (Figure 8).

DEQ encourages EPA to review and verify these results.

Comments on Onroad Emission Rates

A review of the 2011 NOX emission rates for gasoline and diesel vehicles highlight some issues that should be examined by EPA. Figure 12 displays NOX rates per distance for gasoline and diesel vehicles. This plot illustrates a significant difference in emission rates for light-duty diesel vehicles at lower speeds. Therefore, a vehicle's classification as a passenger car or passenger truck may have significant impact on NOX emissions even though both classifications are light-duty vehicles. Figure 13 displays NOX rates per vehicle for gasoline and diesel vehicles. This plot shows significantly larger emission rates for gasoline vehicles than for diesel vehicles. The plot also shows unusually low emission rates for heavy-duty diesel vehicles compared to light-duty diesels. EPA is encouraged to review and verify these unusual emission rates

Comments on Representative County Approach

The SMOKE-MOVES model estimates emissions for a group of individual counties based on the characteristics of a single county. This single county is called a representative county. The criteria for selecting a representative county include fuel properties, fleet age distribution, and emission control programs. The potential impact of this approach is illustrated in Figure 14, which shows the average vehicle age for passenger cars is effectively lowered when a representative county scheme is applied. In addition, hotelling hours for combination long-haul trucks is a newly added model input that was not previously considered in the selection of a representative county. In order to avoid grouping together counties with vastly different hotelling rates, EPA should review and update the representative county selections for each state.

Comments on EPA Age Projection Tool
In previous NODA comments, DEQ noted that the vehicle age distribution inputs used to generate 2018 future year emissions were not the same vehicle age distribution inputs used to develop the 2011 base year emissions. For the 2018 future year emissions, the “Age Distribution Projection Tool” developed by EPA was applied and new 2018 vehicle age distribution inputs were created for all counties. Since the 2017eh emissions are derived from the 2018 data, issues associated with the projection tool apply to the 2017 data as well. Figure 15 compares age distribution data for passenger cars between the base year 2011 and the future year 2018 for Virginia’s 12 representative counties. With the application of the tool in 2018, an overall different shape of age distributions was projected in 2018 from 2011. The resulting age distributions for 2018 also contain a large dip (“artificial recession”) at vehicle age 7. These differences in age distribution at the continental United States (CONUS) scale are illustrated in Figure 16. The 2018 age distributions generated by the tool show less variation by county and also yield a younger fleet for passenger cars in 2018 than in 2011.

Comments on Defaults in the NEI
Figure 17 is a review of the MOVES model input for vehicle age distributions supplied by each state for the 2011 National Emissions Inventory (NEI) version 2. Many states experienced difficulty obtaining data for this model input. As a result, most states chose to use MOVES model default data instead of locality-specific vehicle age distribution data. The major exception to this is for passenger cars (21), passenger trucks (31), and light commercial trucks (32). For these light-duty vehicles, many states utilized countyspecific data provided by EPA through the Coordinating Research Council (CRC) A-88 project, MOVES Input Improvements for the 2011 NEI, October 2014. DEQ encourages EPA to continue updating MOVES model defaults and assisting states in obtaining data for the 10 remaining MOVES model vehicle types (e.g. CRC A-100 Improvement of Default Inputs for MOVES and SMOKE-MOVES, February 2017).

WEST

While implementation of the CPP would likely reduce emissions, it is not necessarily the case that impacts will also be reduced. It is likely that application of controls of existing units or installation of new equipment (e.g. turbines) would change the unit’s stack

Peaking units
The emissions from EGU peaking units were previously separated into a file named “ptegu_pk” sector in EPA’s 2011 NEI v1 to facilitate analysis of peaking units. However, this sector no longer exists in the 2011 NEI v2 used by NODA. The peaking units previous identified by EPA were incorporated into the point EGU sector, in which EPA developed

specific diurnal profiles for summer and winter seasons based on hourly continuous emissions monitoring systems (CEMS) info.

To assess the potential accuracy of EPA's modeling analysis for peaking units, emissions data for a facility with peaking units was further assessed. As an example, an existing facility has ~380 megawatt (MW) total peaking capacity spread over five simple cycle combustion turbines that are typically used during the summer months with < 10% capacity overall. For this facility there is no planned operation in 2023 (EPA-HQ-OAR-2016-0751-0026.xlsx), while the station is not listed as being retired in NEEDS v5.16 database (EPA-HQ-OAR-2016-0751-0030.xlsx). This indicates a discrepancy and potentially a failed quality assurance (QA) check.

Based on this individual example and a lack of transparency for all peaking unit emissions, it does not appear that EPA fully considered this source category and future changes in sufficient detail and as a result it is possible that the projected emissions are inaccurate. It is recommended to keep peaking emissions separate from other point sources information and to document the emissions and processing as part of TSDs in order to improve the accuracy, traceability, and reliability of the analysis

Oil and gas

EPA estimated O&G emissions with 2011 oil and gas activity data with the Oil and Gas Tool along with inputs from state/local/tribal agencies. There has been a lot of effort and expense put into characterizing O&G emissions in western basins by WESTAR, and their O&G activities, controls and emissions inputs developed (3SAQS/WAQS). While it is not clear whether EPA has incorporated the results from those extensive studies done in several western basins (e.g. Uinta, San Juan, Southwest Wyoming, etc.). We noticed significant data discrepancy between EPA's 2011 national emissions inventory (NEI) and WESTAR's 2011 O&G emissions studies in both point and non-point O&G emissions (for more detail comparisons, please refer to "Attachment 1 - Oil and Gas Emissions Comparisons"). These discrepancies may be further compounded by the application of growth and control assumptions used to project 2011 emissions to 2023. We recommend EPA to improve O&G emissions estimates by incorporating existing estimates from western states or WESTAR to ensure the NEI data for O&G sector are complete, and develop realistic approaches to growth and control of emissions from the rapidly changing western oil and gas sector.

Fires

Regional wildfires have widespread effects on background ozone levels. EPA used SMARTFIRE2-BlueSky framework processed through the NEI to estimate fire emissions for this analysis, while it seems that PMDETAIL provides more detailed fire inventories for photochemical modeling than SMARTFIRE.
There have been several studies (e.g. 3SAQS, SNMOS) that use fire emissions for 2011 that were generated by the Particulate Matter Deterministic and Empirical Tagging and Assessment of Impacts on Levels (PMDETAIL) study. PMDETAIL developed 2011 fire emission using satellite data and ground detect and burn scar, in addition to other data, with a slight modification (Mavko, 2014) to the methodology used in the Deterministic and Empirical Assessment of Smoke's Contribution to Ozone Project (DEASCO3) study for the 2008 modeling year (DEASCO3, 2013). It was believed PMDETAIL/DEASCO3 provides a more complete satellite and surface fire dataset over SMARTFIRE inventory. Due to the predominance of fires in the western U.S. and the sub-part air quality model performance for western receptor locations, it is recommended that EPA replace the SMARTFIRE emissions dataset with PMDETAIL when conducting a revised modeling analysis in order to improve western model performance. Furthermore, it is recommended that removal of fires (as would be conducted as part of an exceptional events demonstration) should be considered. For model performance tests and consistency with monitored design value calculations, inclusion of fire emissions is required. However, a second set of runs excluding fires in the base and future years and removing fires from monitored design values would confirm that fire emissions are not influencing the conditions and the source apportionment results inadvertently.

Biogenic

EPA used Biogenic Emissions Inventory System (BEIS) to predict biogenic emissions without evaluating alternative model, e.g. Model of Emissions of Gases and Aerosols from Nature (MEGAN). Importantly, EPA has considered replacing BEIS in its CMAQ modeling. MEGAN 2.1 has significant model changes and improvement in predicting biogenic emissions in the western-states. Improvements in MEGAN 2.1 for western areas include: western-specific inputs (WRAP Biogenic Emissions Improvement Project), more accurate emissions factors based on better data sources (satellites and field studies), and higher temporal and spatial variability of land cover and other environmental inputs. Because EPA used APCA to determine the ozone contributions, different biogenic emission models could impact the overall source apportionment results. We suggest EPA conduct sensitivity testing to identify which biogenic model best represent biogenic emissions from western regions or evaluate and mitigate the implications of using a potentially less accurate biogenic model.

Lightning NOx

NOx can be formed in lightning channels when heat released by the electrical discharge causes the conversion of nitrogen (N_2) and oxygen (O_2) to nitrogen oxide (NO). Field studies have shown that the formation of NO from lightning can be as high as 700 mole-NO/flash (Murray, L.T. 2016; Pollack *et al.* 2016) and can contribute 3-4 ppbv of background surface ozone, and up to 18 ppbv during individual events (Murray, 2016 and references therein). Lightning NOx emissions has been implemented in most global model and regional air quality modeling studies (Jourdain L, *et al.* 2010;). It is also a key component of emission inventories in several Air Quality Studies for western US (3SAQS 2015; SNMOM 2016).

It is important to include Lightning NOx (ltnox) emissions as part of air quality modeling exercise as its contribution to background surface ozone cannot be ignored. While ltnox emissions may be kept constant in both base and future year model scenarios, the missing ozone contribution from ltnox can have effects on overall relative response factor (RRF) calculations that EPA employs to determine the future year design values. It is recommended that EPA include lighting NOx emissions as part of a revised modeling analysis

WI

EPA continues to apply national default control data to project future industrial point source emissions. This approach mischaracterizes the potential for emissions reductions actually available at these facilities. WDNR previously included this recommendation in its 2014 comments on EPA's proposed 2018 Emissions Modeling Platform.[8] WDNR reiterates the need for EPA to project future industrial point source emissions using facility- and unit-specific information. Treatment of this sector should be similar to the unit-specific characterizations that are done for EGUs. Applying national default control levels by SCC categories is more appropriate for sectors such as nonpoint sources, which includes numerous small units whose emissions are challenging to track at the unit or facility level. WDNR is submitting updated industrial point source control information as part of these comments to ensure EPA's projected emissions inventory for the state is more accurate. However, any projected control levels in the comments here – and any associated projected residual emissions estimates – do not limit the amount of future actual emissions allowed from industrial point sources in Wisconsin. Also, any emissions budget setting that involves industrial point sources should be done under a separate process whereby WDNR could perform a separate set of projected emissions for Wisconsin's industrial point sources.

Since certain boilers were required to comply with Industrial, Commercial and Institutional Boiler Maximum Available Control Technology (ICI Boiler MACT) by January 2016 (or January 2017, if a one-year compliance extension was granted by the state), WDNR is now aware of committed controls at a number of larger emission units subject to ICI Boiler MACT. Based on this information, WDNR makes the following control level recommendations for EPA's use in projecting future year emissions for Wisconsin's industrial point sources:

- Use the WDNR recommended NOx and SO_2 control levels for specific units in Wisconsin, specified in Figure 1.
- Add four new units that have recently been installed in Wisconsin to the 2017/2023 industrial point source inventory, as specified in Figure 2.
- Continue to allow for a procedure whereby Wisconsin can provide unit-level control updates routinely to allow for more reasonable projected emission reductions.

In June 2014, WDNR asked EPA to use a percent growth rate that reflects fuel use projections from EIA's "2014 Annual Energy Outlook – Industrial Sector Key Indicators and Consumption." EPA appears to have implemented this recommendation, and should continue to do so in future versions of its modeling platform.

EPA needs to take more responsibility for ensuring that its commercial marine and on-road inventories are accurate. For example, EPA's spatial allocation of commercial marine emissions in the Great Lakes does not accurately reflect the diversity of activity in the lakes. For most of Lake

Michigan, emissions are allocated to a single shipping lane running from the northeast corner of the lake to the southwest corner (Chicago); this results in zero emissions for the northern Wisconsin lakeshore counties (Kewaunee, Manitowoc and Sheboygan), with all emissions allocated to the Michigan counties to the east. LADCO is developing updated commercial marine emission estimates and projections for the Great Lakes, as well as for major rivers in the Mississippi River system. WDNR recommends that these updates replace EPA's existing commercial marine emission estimates when LADCO makes this data available.

Review of the on-road emissions for eight Midwestern states indicates a considerable variability in overall annual emission factors (e.g., total statewide emissions divided by total statewide vehicle-miles of travel). WDNR will further review this variability, including examining vehicle classes and road types, in conjunction with a multi-state review coordinated by LADCO. Based on this review, LADCO will provide data updates to EPA, as needed.

Figure 1 includes reductions for some units including retirements by end of 2015. Some new units are also provided in Figure 2.